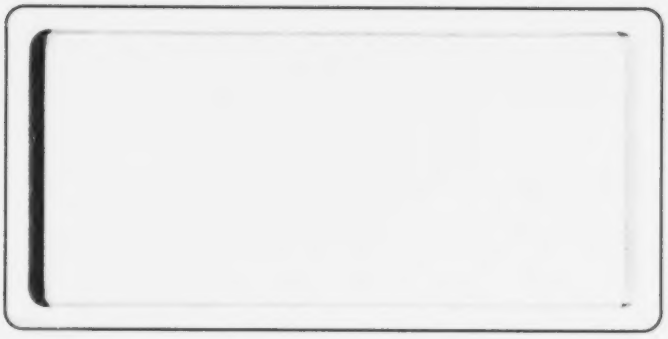

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Neill and Gunter

SUPPLY AND SERVICES CANADA
ENERSOLVE
DEMONSTRATION PROJECT
PHASE NO. 1
MOOSEHEAD BREWERIES LIMITED
SAINT JOHN, NEW BRUNSWICK

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CONTACT IDENTIFICATION: EMR File No. OSQ-84-00392
DSS File No. 14SQ,23440-4-9283-1
DSS Contract Serial No. OSQ84-00392

53pp

Draft: December, 1985
Final: March, 1986

Job No. 11836

AUG 15 1988
MICROMEDIA

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Demonstration Project

Phase No. 1

Moosehead Breweries Limited

Saint John, New Brunswick

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Saint John, New Brunswick

1. Executive Summary

The Moosehead Breweries Limited, Saint John, New Brunswick steam plant has three boilers identified as Boilers No. 1, No. 2 and No. 3.

The extent of the steam plant instrumentation is minimal and very basic in nature and is insufficient to provide the data necessary to fully evaluate the existing steam plant operation. To evaluate on a continuous basis how efficiently the existing control systems operate and how well the boilers maintain the desired steam header pressure requires the following alterations and upgrades to the present systems:

(1) The addition of a steam header pressure transmitter and recording loop at an estimated installed cost of $4,000. The estimated time to complete the work is 8 weeks.

(2) The upgrading of Boiler No. 1 and No. 2 instrumentation and in particular a flue gas oxygen analyzer and recording loop. The estimated installed cost of the upgrade is $15,500.

The estimated time to complete the work is 10 weeks.

(3) Boiler No. 3 has the greatest potential for efficiency improvement and requires a complete new instrument and control package at an estimated installed cost of $70,500.

Th estimated time to complete the work is 16 weeks.

The estimated costs to complete the detailed design engineering for items (1), (2) and (3) above and monitor the results of the modification is $44,250 which includes $17,500 already expended for this Study.

It is concluded that steam plant efficiency and operational results can be significantly improved by the installation of state-of-the-art instrumentation in the Moosehead Breweries' steam plant.

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Approvisionnements et Services Canada

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Projet de démonstration

Phase n° 1

Moosehead Breweries Limited

Saint John (Nouveau-Brunswick)

1. Sommaire général

Les installations de production de vapeur de Moosehead Breweries Limited de Saint John (Nouveau-Brunswick) sont dotées de trois chaudières désignées par chaudières N° 1, N° 2 et N° 3.

Le nombre d'appareils de mesure dont sont munies les installations est réduit au strict minimum. Il s'agit d'appareils élémentaires, incapables de fournir les données nécessaires à l'évaluation des activités courantes des installations de production de vapeur. Pour évaluer de façon ininterrompue l'efficacité du fonctionnement des systèmes de commande existants et du maintien de la pression du collecteur de vapeur, il faut modifier les systèmes actuels et leur apporter les améliorations suivantes:

(1) L'ajout d'un distributeur de pression au collecteur de vapeur et d'un circuit d'enregistrement à un coût évalué à 4000 $, installation comprise. On estime qu'il faudra huit semaines pour faire le travail.

(2) Le perfectionnement des appareils de mesure des chaudières n° 1 et n° 2 et, plus précisément, d'un analyseur d'oxygène des gaz brûlés et d'un circuit d'enregistrement. On évalue à 15 500 $ le coût de cette amélioration.

Selon les estimations, il faudra dix semaines pour terminer le travail.

(3) C'est la chaudière n° 3 qui offre les plus grandes possibilités d'amélioration au niveau du rendement. Il faut un ensemble complet d'appareils de mesure neufs et un bloc de commande dont le coût est évalué à 70 500 $, installation comprise.

On prévoit qu'il faudra seize semaines pour achever le travail.

Il en coûtera, selon les prévisions, 44 250 $ pour mettre au point les détails de conception technique des articles (1), (2) et (3) ci-dessus et pour vérifier les résultats de la modification. De ce montant, 17 500 $ ont déjà été consacrés à la présente étude.

En conclusion, le rendement des installations de production de vapeur et les résultats d'exploitation pourraient s'améliorer considérablement en dotant Moosehead Breweries d'appareils de mesure perfectionnés.

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Demonstration Project

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Moosehead Breweries Limited

Saint John, New Brunswick

2. Introduction

Energy, Mines and Resources, CANMET Energy Research Laboratories, Ottawa, Ontario retained Neill and Gunter Limited, Dartmouth, Nova Scotia under the ENERSOLVE Demonstration Project Program to investigate and prepare a study report on the steam generation facilities of Moosehead Breweries Limited, Saint John, New Brunswick. The study objective was to identify and define those projects that if implemented would result in a more efficient boiler plant operation. The site investigation work has been carried out in consultation with Moosehead Breweries' personnel and the boiler test work has been performed by Bailey Controls, Fredericton, New Brunswick. Because of unforeseen boiler and equipment repairs and the scheduling of the boiler tests, it has been necessary to perform the work over an extended period; however, it is emphasized that the results of the work have not been affected by this extended schedule.

This first draft report summarizes the work accomplished to date and is submitted for review and comment by Energy, Mines and Resources CANMET, Energy Research Laboratories' personnel and Moosehead Breweries' staff. On completion of this review a final report will be prepared in accordance with the contract documents.

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ENERSOLVE

Demonstration Project

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Moosehead Breweries Limited

Saint John, New Brunswick

3. Summary

As a result of the investigations of the boiler plant systems and the combustion tests performed on each of the boilers No. 1, No. 2 and No. 3 during this study, it is concluded that improvements in boiler plant efficiencies and maintenance costs can be made by revisions to existing systems and the addition of modern electronic instruments and controls to specific applications. The recommendations of this report are based on a phased approach as follows:

(1) Improve the plant instrumentation to provide more accurate and relevant data on critical steam plant variables.

(2) Revise and add instruments and controls to the boiler systems with the maximum cost saving potentials.

(3) Based on the data collected and results achieved through the implementation of items (1) and (2), optimize the boiler control systems or other parts of the plant steam system by the possible addition of a feedwater economizer and/or a steam accumulator.

In summary, this study recommends that the monitoring of the critical variables in the Boilers No. 1, No. 2 and No. 3 be improved and that the combustion control system of Boiler No. 3 be replaced with a modern electronic system. The boiler plant operating mode envisaged is that Boiler No. 1 and/or No. 2 would be based loaded at their most efficient operating point and plant load savings would be taken on Boiler No. 3.

The following section No. 3 summarizes the recommendations resulting from this study, and the estimated costs to implement each recommendation.

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Demonstration Project

Phase No. 1

Moosehead Breweries Limited

Saint John, New Brunswick

4. Recommendations and Cost Estimate Summary

The following is a summary of the recommendations and cost estimates detailed in Section 6.

4.1 Steam Plant Header Pressure Recording System

At present there is no steam plant header recording system in the plant. The addition of such a loop is essential to accurately determine the performance of the existing combustion control systems and their correlation with steam flow and boiler water level control.

Two options are available for the addition of this instrument loop:

(1) Install a new electronic (4-20 ma) steam header pressure transmitter and record the variable in either the Boiler No. 1 or No. 2 circular chart recorder.

Estimated Installed Cost $4,000

(2) Install the new electronic (4-20 ma) pressure transmitter and include the recording of the variable as part of the proposed revisions to Boiler No. 3 combustion control system. See Section 3.3 following.

4.2 Boilers No. 1 and No. 2

The correction of primary element problems on the steam flow monitoring loop and the addition of a flue gas temperature monitoring loop on both Boiler No. 1 and No. 2 is required to provide plant operating and maintenance personnel with the minimum data required to monitor the performance of the packaged combustion control (mechanical-parallel) systems. The addition of a flue gas oxygen analyzer on each boiler may be justified at a later date should operation with reliable steam flow and flue gas temperature monitoring indicate a more optimum combustion system calibration could be maintained if the flue gas oxygen content were available to operating and maintenance personnel.

Estimated installed costs for each boiler system revision are as follows:

(1)	Correct existing steam flow element installation	$ 1,500
(2)	Add flue gas temperature monitoring system	4,000
(3)	Sub-Total	$ 5,500

(4)	Add flue gas oxygen monitoring system	$10,000
(5)	Total each boiler	$15,500

Based on the combustion tests for Boilers No. 1 and No. 2 (Appendix No. 1), there is little economic justification to revise the existing combustion control system.

4.3 Boiler No. 3

The combustion tests for Boiler No. 3 (Appendix No. 1) indicate that there are savings to be achieved by the addition of a modern combustion control system. If this recommendation were implemented, then the steam plant, header pressure control system outlined in Section 3.1 would be integrated into this system.

Estimated installed costs for proposed steam header pressure, combustion control and two element feedwater system.

(1)	Install an electronic (4-20 ma) steam header pressure transmitter	$ 2,000
(2)	Install an electronic (4-20 ma) steam flow transmitter	2,000
(3)	Install an electronic (4-20 ma) flue gas temperature transmitter	2,000
(4)	Install an electronic (4-20 ma) flue gas oxygen transmitter	10,000

(5) Install an electronic (4-20 ma) drum water level transmitter $ 2,000

(6) Supply a totally enclosed vertical panel (32" x 14" x 86") with the following components:

- Two, 3 pen strip chart recorders to record:
  - Steam Header Pressure
  - Feedwater Pressure (optional)
  - Feedwater Temperature (optional)
  - Steam Flow
  - Flue Gas Temperature
  - Flue Gas Oxygen
- Micro-processor based combustion control system with capacity for two element feedwater control system (Bailey Net 90 or equivalent)
- Manual/Automatic digital control stations for control of:
  - Steam Header Pressure
  - Fuel Oil Flow
  - Combustion Air Flow
  - Oxygen Trim
  - Drum Water Level

Installed Cost $50,000

(7) Install Electronic to Pneumatic (I/P) Converters on oil flow valve, combustion air control drive and feedwater control valve 2,500

(8) Total Installed Cost Item 3.3 $70,500

4.4 Feedwater Control on Boilers No. 1 and No. 2

Should operating experience indicate that the existing on-off drum water level control systems are inducing cyclic steam generation or excessive thermal shocks in the boilers, then a local modulating control loop installation could be recommended.

Estimated installed cost per boiler $10,000

4.5 Cost Estimate for Engineering and Monitoring the Proposed Instrumentation and Control Modifications

(1)	Data gathering and analysis (This Study)	$17,500
(2)	Detailed Engineering, specifications, selection of suppliers and contractors and field installation inspection	$20,000
(3)	Monitoring the performance of the installations for 9 months	$ 6,750
	Total	$44,250

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Moosehead Breweries Limited

Saint John, New Brunswick

5. Existing Facility Description

The following describes the existing operation at Moosehead Breweries' Saint John plant with particular reference to steam load demand and the boiler plant.

5.1 Plant Operation

The Saint John plant of Moosehead Breweries Limited produces draft and bottled beer for domestic and export markets. Appendix No. 2, Drawing B-403, shows a simplified process flow diagram. Present plant capacity is near one million hectolitres per year. Export market development over the last six years has launched several expansion projects which have tripled the capacity of the plant. Included in the facilities upgrading were changes to the steam generation plant to its present state. Potential exists in the brewery for further capacity expansions of major proportions and many of the existing plant systems are adequate to accommodate future production increases.

5.2 Process Steam Demand

The Saint John operation of Moosehead Breweries Limited is typical of Canadian breweries. The brewing

process is performed on a 3 hour batch cycle or 8 brews per 24 hour shift. Depending on seasonal demands, the packaging operations run on a single or two 8 hour shifts. The brewing and packaging operations are the two major steam consumers in the plant. The seasonal variations in production volume typically indicates that peak season production rate is 33% greater than the annual average.

The brewing operation uses steam in the mash mixer for temperature control during starch conversion and to raise the temperature at the completion of conversion to stop enzymatic action. Steam is used in the jackets of the holding tank and wort kettle to raise the temperature of the wort to boil. A percolator within the kettle uses steam to generate the vigorous and continuous boiling necessary to sterilize the wort, to evaporate undesirable flavours and to condition the wort. Steam is also used in the brewing department to heat water in preparation for mashing and sparging operations. This heating load occurs only at the first of each week because the requirements are satisfied by heat exchange with wort cooling after the first brew of the week reaches that point in the cycle.

Other minor steam uses in production include plant heating, carbon dioxide evaporation and heating of cleaning solutions.

The packaging plant operates two bottling lines with one designated to export and one to domestic production. Kegging facilities for export and domestic product use modest amounts of steam for keg cleaning.

The domestic bottling line uses a bottle washer and pasteurizer which are major steam users. These steam loads peak during system start-up and remain fairly constant during the shift. The export line uses a pasteurizer and bottle rinser. Of these loads, only the export bottle rinser returns condensate to the system.

The packaging plant also uses steam for heating, cleaning and other minor uses. Appendix No. 2, Drawing B-402, compares the theoretical steam load for the plant with the actual output as measured by the steam flow chart recorders. Based upon the test report, the steam flow chart cannot be regarded as an accurate measurement but the character of the load is very clear from this diagram. Spikes occurring in the actual steam consumption are accounted for by the fact that heat transfer rates vary through the process depending on temperature differences and convection conditions within the vessel.

The process demands of the brewing cycle on the steam supply cannot be compromised. Product quality demands close temperature control and specific heating rates. Increases and decreases in demand occur sharply but cannot, in most cases, be modulated without jeopar-

dizing quality or safety. High production rates, necessary to maintain economical use of plant and labour, also place steam availability as a high priority. Based on discussions with the Brewery management and operating personnel, this study has considered the process steam demands as fixed and no attempt has been made to identify opportunities of reducing steam demand at the point of use.

The potential does exist, however, to install a Ruth's type steam accumulator operating between the 100 psig and 60 psig steam headers. Such an accumulator, if charged at 100 psig, could supply 3.52% of its mass as flash steam at 60 psig. The accumulator would allow storage of energy during periods of falling steam demand with production of steam during periods when steam demand is rising. The addition of a steam accumulator to the system would reduce the frequency and magnitude of boiler modulation resulting in an improved overall efficiency of the operation and a narrower band of steam load swings. Smaller load swings would result in improved boiler fuel combustion and keep the load swing within the capability of one boiler. A fully charged 75 hectolitre accumulator could supply 5000 lb/hr. of steam for a five minute peak on this basis.

5.3 Boiler Plant

Appendix No. 2, Drawing B-401, shows a simplified steam and condensate diagram for the boiler plant. Boilers No. 1 and No. 2 are horizontal fire tube units rated 800 h.p., (26,500 lbs/hr. @ 100 psig and F.W. @ 212°F); manufactured by Cleaver Brooks. They share a common stack. Bunker "C" oil, air atomized, is burned in both Boilers No. 1 and No. 2.

Boiler No. 3 is a water tube boiler rated at 25,000 lb/hr.; manufactured by Foster Wheeler. Bunker "C" oil, steam atomized, is burned in this unit.

Boiler No. 4 is an obsolete unit preserved for emergency use only and is limited in capacity such that it is barely adequate to prevent plant freeze-up during the winter months. It is well suited to this purpose because it has the capability to generate steam on natural draft with no auxiliary fans. It is generally not used and is not considered in this analysis.

The steam distribution system generally supplies all users at nominal 100 psig except the packaging plant which is supplied at 60 psig through a pressure reducing valve.

Condensate is not returned from No. 1 mash mixer (now out of service), the soaker, the pasteurizers or the fuel oil heaters. Condensate is returned from most other sources via flash tanks and pumps or gravity returns. All returns discharge to the low pressure connection on the deaerator storage tank.

Two parallel connected electrically driven boiler feed pumps, plus an emergency steam driven pump, supply the feedwater to all boilers. The feedwater regulators on boiler No. 1 and No. 2 operate in an on-off mode based on signal from a level switch. Boiler No. 3 has modulating thermo-hydraulic feedwater control but the system does not appear to operate smoothly.

Operating records for the plant indicate the following. Quantities are in hectolitres, Hl.

Period	Hl. of Beer Brewed	Hl. of Fuel Oil Consumed	Hl. of Fuel Oil Per Hl. of Beer
Nov. 81 - Oct. 82	666,365	33,836	.0508
Nov. 82 - Oct. 83	741,267	32,390	.0437
Nov. 83 - Oct. 84	827,846	33,085	.0400
Nov. 84 - Oct. 85	774,486	33,788	.0436

The improvement in the Hl. of fuel oil per Hl. of beer ratio between the period (November 1981 - October 1982) and the period (November 1982 - October 1983) is attributable to the installation of boiler No. 1, which replaced a less efficient unit. The improvement between the period (November 1982 - October 1983) and the period

(November 1983 - October 1984) is the result of the installation of boiler No. 2. The increase in the Hl. of fuel oil per Hl. of beer between the periods (November 1983 - October 1984) and (November 1984 - October 1985) is indicative of the operating problems being experienced with boiler No. 3 during the latter period..

Plant personnel report that the average cost per litre for oil is 24.53 cents or a yearly oil bill of (.2453 x 3,378,800) $828,820.

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Saint John, New Brunswick

6. Discussion

6.1 Combustion Tests

The report from Bailey Control for the boiler combustion tests conducted by their service technician are included in Appendix No. 1 of this report.

The report has been reviewed with the Bailey Control's representative and the following noted:

(1) Boilers No. 1 and No. 2

The combustion control systems of both boilers operate satisfactorily in the steady-state condition. Although the flue gas excess air was higher during the test than desirable, it was not excessive. The excess air varied from a low of 22% to a high of 38% over the load range which compares to a desirable target of 15 to 20 percent. It is also noted that the flue gas exit temperature was not excessive with variations from 370°F to 340°F which ensures a minimum of back-end and stack corrosion. It was not possible to obtain meaningful results during transi-

ent conditions because of the lack of adequate instrumentation and the continuous cycling of the control system while attempting to maintain steam header pressure at the setpoint value.

It is concluded that the existing combustion control systems can be further calibrated to approach the desired excess air conditions. Because of the low flue gas exit temperature (370°F to 340°F) there is a minimal improvement in boiler efficiency for a decrease in excess air from 40% to 15%. Refer to, "Changes in Boiler Heat Loss versus changes in Excess Air" in Appendix No. 1.

The recommendations of this report are based on providing the operating and maintenance personnel with the minimum required information, in a continuous and accurate fashion, to allow them to monitor Boilers No. 1 and No. 2 when on-line and take corrective action as required to maintain optimium operation.

Based on a projected improvement in boiler efficiency of 1% and assuming that 50% of the yearly oil costs of $829,000 are expended in Boilers No. 1 and No. 2, then the annual savings are calculated as follows:

Annual Saving = (.5)(829,000)(.01)

= $4,145

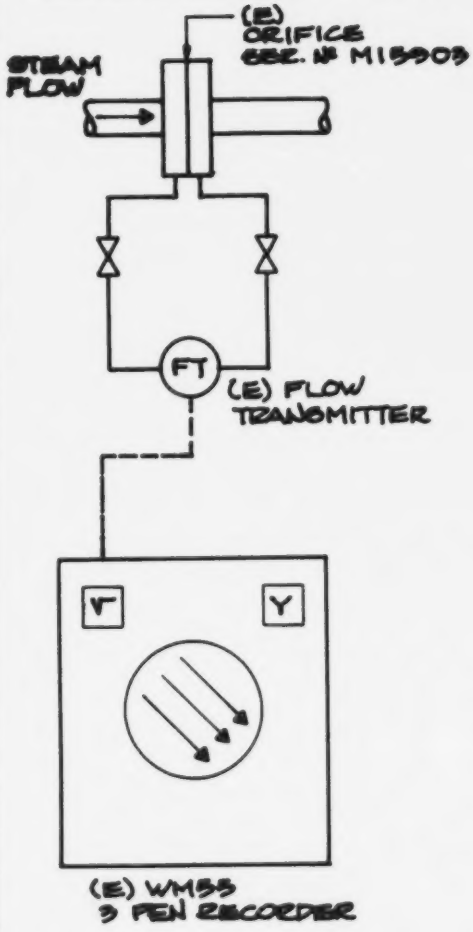
The sketches following indicate schematically the existing and recommended revisions to the Boilers No. 1 and No. 2 instrumentation.

BOILER Nº1

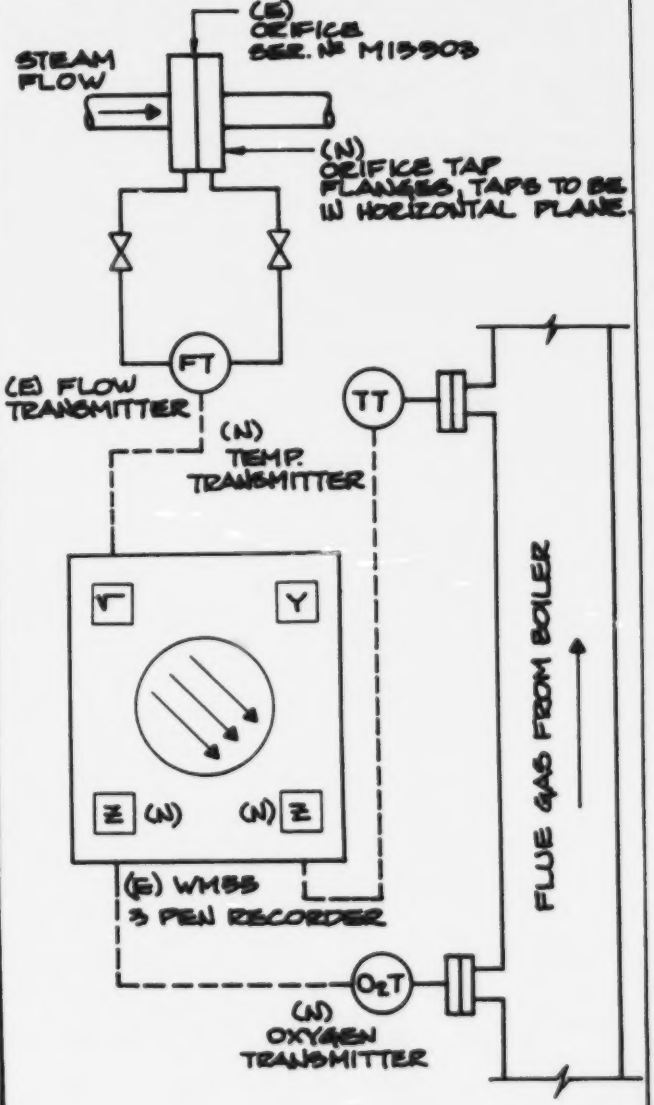
CLEAVER BROOKS, 800 HP, 100 PSIG SATURATED FIRE TUBE BOILER C/W MECHANICAL OPERATED PARALLEL COMBUSTION CONTROL SYSTEM OPERATING FROM HEADER PRESSURE AND AN ON-OFF FEEDWATER CONTROL SYSTEM.

(E) - EXISTING
(N) - NEW

EXISTING METERING SYSTEM



RECOMMENDED METERING SYSTEM

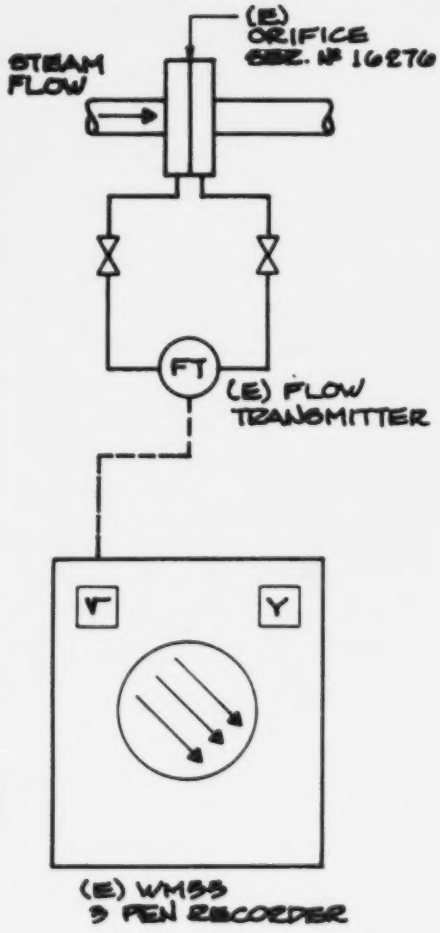


BOILER Nº2

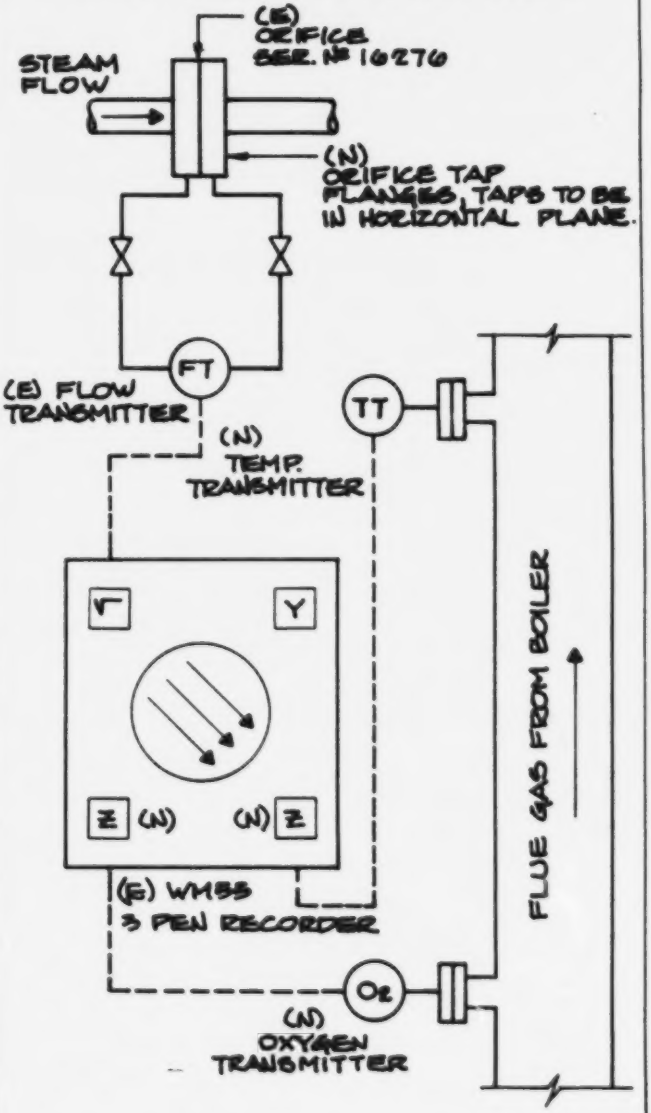
CLEAVER BROOKS, 800 HP, 100 PSIG SATURATED FIRE TUBE BOILER C/W MECHANICAL OPERATED PARALLEL COMBUSTION CONTROL SYSTEM OPERATING FROM HEADER PRESSURE AND AN ON-OFF FEEDWATER CONTROL SYSTEM.

(E) - EXISTING
(N) - NEW

EXISTING METERING SYSTEM



RECOMMENDED METERING SYSTEM



(2) Boiler No. 3

The combustion control system on Boiler No. 3 is a very rudimentary system. The flue gas temperature recorded during the combustion tests varied from a low of 510°F to 625°F and the flue gas excess air from a low of 25% to a high of 52%. With this type of boiler a 15% excess air is a reasonable target. Because of the higher exit flue gas temperature, in comparison to Boilers No. 1 and No. 2, a decrease in excess air from 40% to 15% will provide an increase in boiler efficiency of 2.5%. Refer to, "Changes in Boiler Heat Loss versus Changes in Excess Air" in Appendix No. 1. It is to be noted that at a specific load the changing of excess air has a negligible affect in changing gas temperature. Because Boiler No. 3 provides the best opportunity to increase fuel burning efficiency and thence provide the best return on investment (ROI), it has been chosen as the boiler on which it is recommended that the combustion system be upgraded to a state of the art system.

Based on a projected improvement in boiler efficiency of 2.5% and assuming that 50% of the yearly oil costs of $829,000 are expended in Boiler No. 3, then the annual saving are calculated as follows:

Annual Saving = (.5)(829,000)(.025)

= $10,363

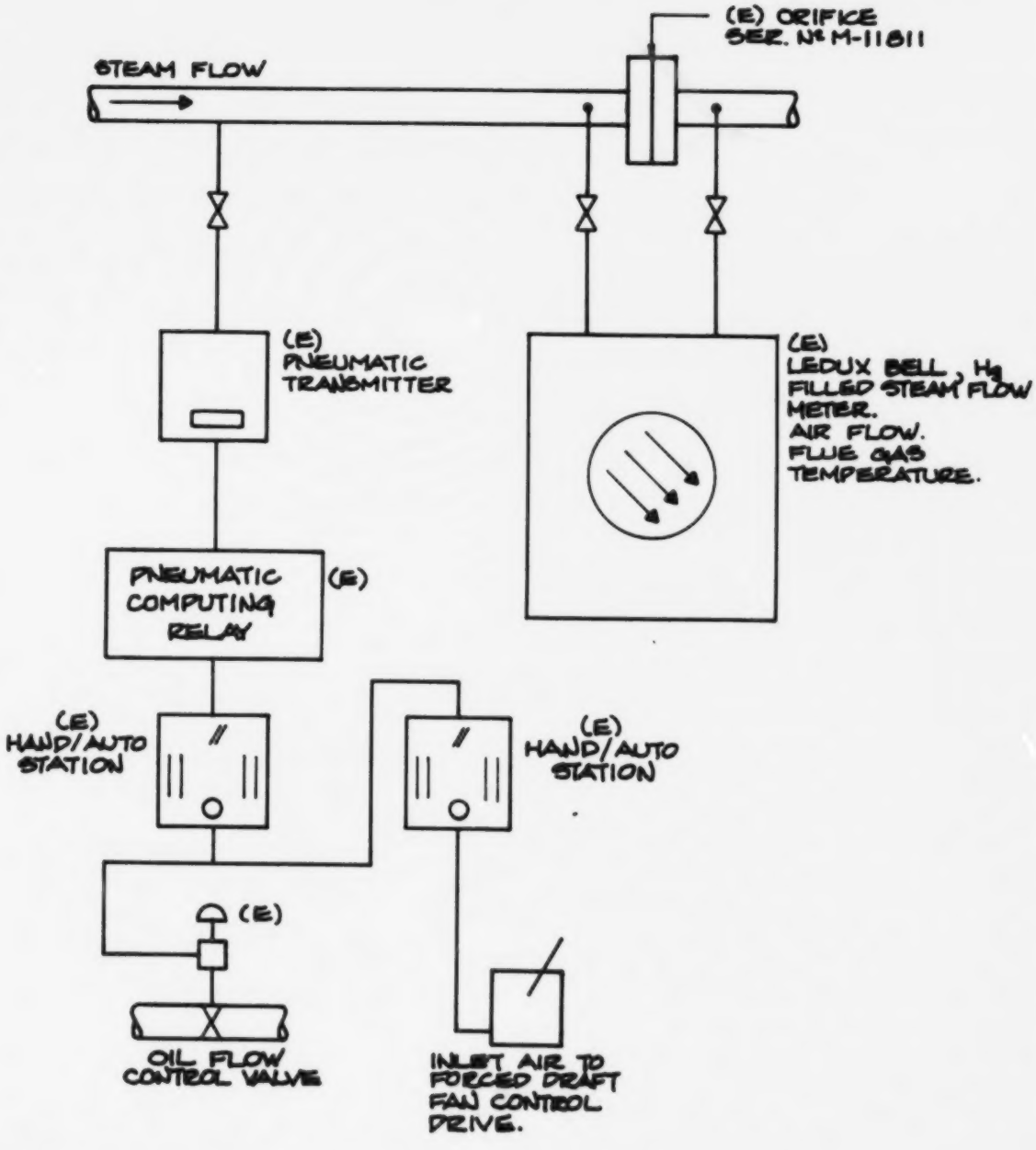
The combustion tests record that the Bunker "C" oil temperature varied from 182°F to 194°F of the burner during the tests. The affect of temperature on fuel oil viscosity is well documented in graphical form in many publications. It is recommended that the viscosity specification of the burner be checked against the viscosity - temperature specification of the fuel being purchased to ensure a proper oil temperature which results in the proper viscosity for good atomization and the resulting optimum combustion. It is recommended that the oil temperature measuring gage be checked for accuracy and then corrective measures taken as required. The sketches following indicate schematically the existing and recommended revisions to the Boiler No. 3 Metering and Combustion Control Systems.

BOILER Nº 3

FOSTER WHEELER, 23,000 LBS/HR., 100 PSIG SATURATED WATER TUBE BOILER C/W A PNEUMATIC PARALLEL COMBUSTION CONTROL SYSTEM OPERATED FROM HEADER PRESSURE AND A SINGLE ELEMENT PNEUMATICALLY OPERATED FEEDWATER SYSTEM.

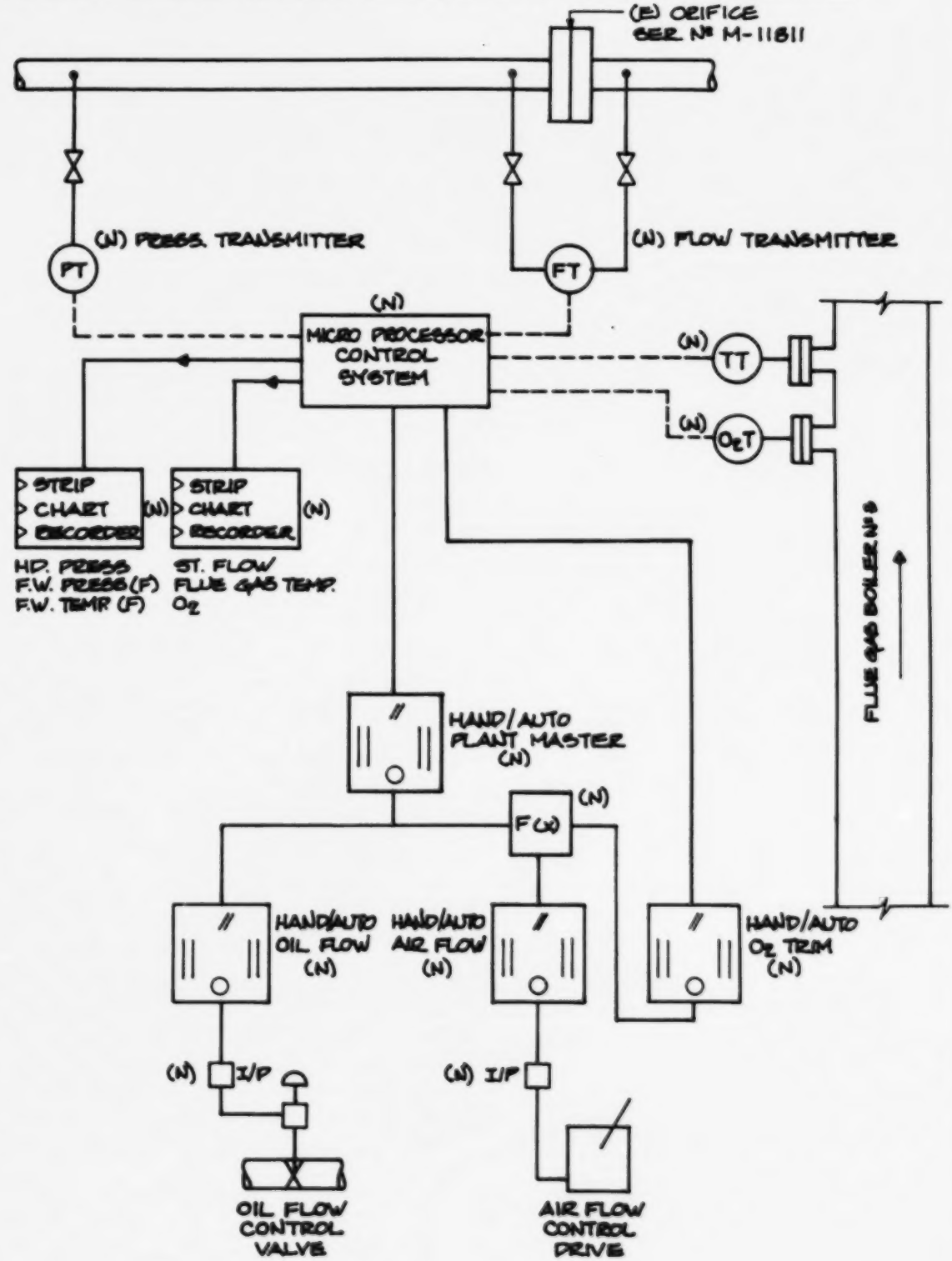
(E) - EXISTING
(N) - NEW

EXISTING METERING AND PNEUMATIC COMBUSTION CONTROL SYSTEM



BOILER Nº 3

PROPOSED NEW ELECTRONIC METERING AND COMBUSTION CONTROL SYSTEM



6.2 Steam Flow Metering

The original specification sheets for the steam flow measurements from Boilers No. 1, No. 2 and No. 3 are included in Appendix No. 1. The following comments are based on an external visual inspection of each installation.

(1) Steam Flow Boiler No. 1

The specification sheets indicates a flanged top installation for the meter connection, whereas the inspection of the installation indicates that the K1 and K2 connection have been made approximately one pipe diameter upstream and one-half pipe diameter downstream from the primary element. This inspection indicates a Vena Contracta type installation. It is recommended that the installation be revised to agree with the specification sheet.

(2) Steam Flow Boiler No. 2

The take-offs from the primary element flanges are in the vertical, whereas ISA practice requires the connections from the side. Because there is no way to vent the high point in the instrument lines there is probably air entrapment adding to a metering error. It is recommended that the installation be revised to agree with the specification sheet.

(3) Steam Flow Boiler No. 3

This installation is in accordance with the Specification Sheet.

6.3 Drum Water Level Control

(1) Boilers No. 1 and No. 2

The feedwater controls for Boilers No. 1 and No. 2 operate in an on-off manner between specified upper and lower drum water level measurements. The rapid variations in drum water level requires a fluctuation in the firing rate when a particular boiler is on header pressure control. A better operation with less stress on the boilers would be accomplished by the installation of modulating type of control system.

(2) Boiler No. 3

The existing Boiler No. 3 feedwater control is a single element Taylor pneumatic system. Should the decision be made to revise the combustion control system, it is recommended that a two element system be installed as part of the upgrade.

6.4 Economizer and Accumulator

With the installation of the instrumentation to measure the critical system variables, data would be available to allow an analysis of the merits of installing an economizer on Boiler No. 3 and/or a Ruth's accumulator between the 100 psig to 60 psig steam supply system.

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7. Cost Estimates

The cost estimates outlined in Section 4 of this report are preliminary in that they are based on Neill and Gunter's most recent experience for this type of installation and discussions with Bailey Controls. It is recommended, however, that prior to committing capital funds for any of the revisions outlined that specifications be prepared for the modifications chosen and competitive pricing obtained from acceptable contractors for both equipment supply and installation.

APPENDIX NO. 1

(1) Graph:
Changes in Boiler Heat Loss
Versus
Changes in Excess Air

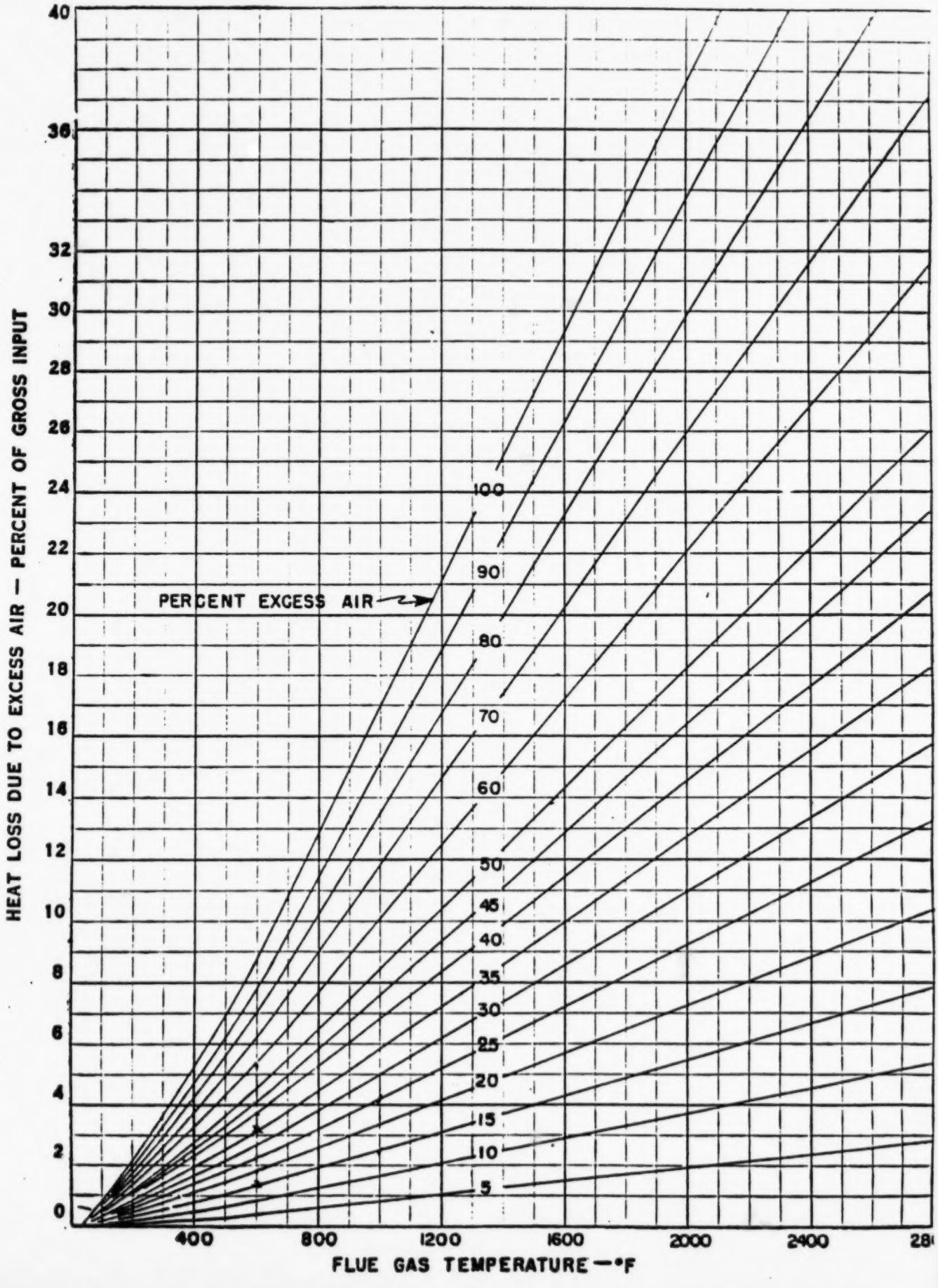
(2) Boilers No. 1, No. 2 and No. 3
Combustion Tests

(3) Boilers No. 1, No. 2 and No. 3
Primary Element Specification Sheets

APPENDIX NO. 1

Graph:

Changes in Boiler Heat Loss
Versus
Changes in Excess Air


HEAT LOSS DUE TO EXCESS AIR — PERCENT OF GROSS INPUT
40
36
32
30
28
26
24
22
20
18
16
14
12
10
8
6
4
2
0
PERCENT EXCESS AIR
100
90
80
70
60
50
45
40
35
30
25
20
15
10
5
400
800
1200
1600
2000
2400
FLUE GAS TEMPERATURE — °F

APPENDIX NO. 1

Boiler No. 1

Combustion Tests

APPENDIX A

Bailey CANADA

COMBUSTION TEST AND AIR FLOW ADJUSTMENT

COMPANY	Moosehead Breweries Limited	DATE	October 31/85
PLANT	Saint John, New Brunswick.	S.E.O. No.	
TYPE		By:	A. Blue/R. Menard
LOCATION	Saint John, New Brunswick.	Cust. Order	

BOILER DATA

Boiler No.	1
Boiler-Make	Cleaver Brooks
Boiler-Type	Fire Tube Model CB600-800
No. Passes & Type Baffles	-
Economizer – Yes ☐ No ☒	
Draft (Type as F.D., I.D., etc.)	F.D. Only
Air Heater-Type & Make	None
Steam A.H. Size	None
Feedwater Regulator-Type & Make	On/Off McDonnell & Miller Inc
Combustion Control-Type & Make	Cleaver Brooks Jackshaft
Boiler Max. Cap. (Design)	800 h.p. 223 USGPH
Burning Equipment-Type & Make	Bunker C Oil (#6) Air Atomized Propane Ignitors

METER DESIGN DATA

Meter Type BQ Class DOZY No. 820128

Press. psig

Temp. °F

Max. Meter Capacity 0-30,000 pph

Chart No.

Type Primary Element Orifice

Main Header Press. Cont. Set Point

AIR FLOW MECHANISM

BK/KC ☐ Diaphragm ☐	Bells Round ☐ Rect. ☐	Displacer Small ☐ Large ☐

Fuel Burned

Test No.	1	2	3		
Date of Test	Oct. 22/85				
Duration Hours	15m	15m	15m		
Steam Flow (as read) x 1000 lbs/hr	20	15	10		
Steam Flow Correction Factor	-	-	-		
Fuel Flow (as read) x =	-	-	-		
Air Flow (relative)	-	-	-		
Steam Press. (Drum) psig	104	104	104		
Steam Press.-Prim. Elem. psig	-	-	-		
Steam Temp. °F-Drum/SPHTR. out	Sat.	Sat.	Sat.		
Steam Press.-Main Hdr.	-	-	-		
Feedwater Temp. °F	212	212	212		
Feedwater Supply Press.	140	140	140		
CO_2 % by volume	11.4	12.3	11.4		
O_2 % by volume	6	5	6		
CO % by volume	0	0	0		
Total Air (Test) %	138	130	138		
Total Air (Final) %	-	-	-		
Flue Gas Temp. °F Leaving Blr.	370	360	340		
Flue Gas Temp. °F Leaving Air Heat.	-	-	-		
Air Temp. °F Entering Air Heater	-	-	-		
Air Temp. °F Leaving Air Heater	-	-	-		
Burner Fuel Press.	47	46	44		
Burner Atm. Stm. Press.	-	-	-		
Fuel Supply Press.	155	155	155		
Burner Fuel Temp. °F	216	220	225		
Burners used					
Burner Tip Size					

Reason for Selecting Total Air (Final)

AIR FLOW MECHANISM CALIBRATION

Radius "R" =

Differential or Total Grams (Inc. Pan)	Chart Readings	Transmitter Output

F & S located to measure relative Air Flow

Flame & Furnace conditions (per each test load)

Stack Conditions (per each test load)

APPENDIX NO. 1

Boiler No. 2

Combustion Tests

Bailey CANADA

COMBUSTION TEST AND AIR FLOW ADJUSTMENT

COMPANY Moosehead Breweries Limited
PLANT Saint John, New Brunswick.
TYPE
LOCATION Saint John, New Brunswick.

DATE October 31/85
S.E.O. No.
By: A. Blue/R. Menard
Cust. Order

BOILER DATA

Boiler No. 2
Boiler-Make Cleaver Brooks
Boiler-Type Fire Tube Model CB600-800
No. Passes & Type Baffles -
Economizer – Yes ☐ No ☒
Draft (Type as F.D., I.D., etc.) F.D. Only
Air Heater-Type & Make None
Steam A.H. Size None
Feedwater Regulator-Type & Make On/Off McDonnell & Miller Inc
Combustion Control-Type & Make Cleaver Brooks Jackshaft
Boiler Max. Cap. (Design) 800 h.p. 223 USGPH
Burning Equipment-Type & Make Bunker C Oil (#6)
Air Atomized Propane Ignitors

METER DESIGN DATA

Meter Type BQ Class DOZY No. 840084
Press. psig
Temp. °F
Max. Meter Capacity 0-30,000 pph
Chart No.
Type Primary Element Orifice
Main Header Press. Cont. Set Point

AIR FLOW MECHANISM

BK/KC ☐	Bells	Displacer
Diaphragm ☐	Round ☐ Rect. ☐	Small ☐ Large ☐

Fuel Burned

Test No.	1	2	3		
Date of Test	Oct. 22/85				
Duration Hours	15m	15m	15m		
Steam Flow (as read) x 1000 lbs/hr	25	20	15		
Steam Flow Correction Factor	-	-	-		
Fuel Flow (as read) x =	-	-	-		
Air Flow (relative)	-	-	-		
Steam Press. (Drum) psig	106	104	104		
Steam Press.-Prim. Elem. psig	-	-	-		
Steam Temp. °F-Drum/SPHTR. out	Sat.	Sat.	Sat.		
Steam Press.-Main Hdr.	-	-	-		
Feedwater Temp. °F	212	212	212		
Feedwater Supply Press.	140	140	140		
CO_2 % by volume	12	13.0	12.2		
O_2 % by volume	5.2	4	5		
CO % by volume	0	0	0		
Total Air (Test) %	131	122	130		
Total Air (Final) %					
Flue Gas Temp. °F Leaving Blr.	370	350	335		
Flue Gas Temp. °F Leaving Air Heat.	-	-	-		
Air Temp. °F Entering Air Heater	-	-	-		
Air Temp. °F Leaving Air Heater	-	-	-		
Burner Fuel Press.	46	50	50		
Burner Atm. Stm. Press.					
Fuel Supply Press.	155	155	155		
Burner Fuel Temp. °F	225	230	230		
Burners used					
Burner Tip Size					

Reason for Selecting Total Air (Final)

AIR FLOW MECHANISM CALIBRATION

Radius "R" =

Differential or Total Grams (Inc. Pan)	Chart Readings	Transmitter Output

F & S located to measure relative Air Flow

Flame & Furnace conditions (per each test load)

Stack Conditions (per each test load)

APPENDIX NO. 1

Boiler No. 3

Combustion Tests

Bailey CANADA

COMBUSTION TEST AND AIR FLOW ADJUSTMENT

COMPANY Moosehead Breweries Limited
PLANT Saint John, New Brunswick.
TYPE
LOCATION Saint John, New Brunswick.

DATE October 31/85
S.E.O. No.
By: A. Blue/R. Menard
Cust. Order

BOILER DATA

Boiler No. 3
Boiler-Make Foster Wheeler
Boiler-Type Water Tube
No. Passes & Type Baffles -
Economizer – Yes ☐ No ☒
Draft (Type as F.D., I.D., etc.) F.D. Only
Air Heater-Type & Make None
Steam A.H. Size None
Feedwater Regulator-Type & Make Taylor Single Element Pneu.
Combustion Control-Type & Make Bailey Parallel
Boiler Max. Cap. (Design) 25,000 pph
Burning Equipment-Type & Make Bunker C
Peabody Stm. Atomized #6 Fuel
Gas Ignitor

METER DESIGN DATA

Meter Type CC36538 Class No. 701578
Press. psig
Temp. °F
Max. Meter Capacity 0-30,000 pph
Chart No. -
Type Primary Element Orifice
Main Header Press. Cont. Set Point

AIR FLOW MECHANISM

BK/KC ☐ Diaphragm ☐	Bells Round ☐ Rect. ☐	Displacer Small ☐ Large ☐

Fuel Burned

Test No.	1	2	3
Date of Test October	21/85	22/85	22/85
Duration Hours	15m	15m	15m
Steam Flow (as read) x 1000 lbs/hr	10	15	20
Steam Flow Correction Factor	-	-	-
Fuel Flow (as read) x =	-	-	-
Air Flow (relative)	-	-	-
Steam Press. (Drum) psig	108	108	108
Steam Press.-Prim. Elem. psig			
Steam Temp. °F-Drum/SPHTR. out	Sat.	Sat.	Sat.
Steam Press.-Main Hdr.	-	-	-
Feedwater Temp. °F	212	212	212
Feedwater Supply Press.	140	140	140
CO_2 % by volume	10.3	11.8	12.6
O_2 % by volume	7.5	5.5	4.5
CO % by volume	0	0	0
Total Air (Test) %	152	134	125
Total Air (Final) %			
Flue Gas Temp. °F Leaving Blr.	510	600	625
Flue Gas Temp. °F Leaving Air Heat.	-	-	-
Air Temp. °F Entering Air Heater	-	-	-
Air Temp. °F Leaving Air Heater	-	-	-
Burner Fuel Press. psig	32	55	68
Burner Atm. Stm. Press. psig	70	100	105
Fuel Supply Press. psig	150	150	150
Burner Fuel Temp. °F	194	190	182
Burners used	1		
Burner Tip Size	-		
Windbox. Press.	1"H_2O	1.8	2.25
Uptake Draft	-40"H_2O	-.40	-.4

Reason for Selecting Total Air (Final)

AIR FLOW MECHANISM CALIBRATION

Radius "R" =

Differential or Total Grams (Inc. Pan)	Chart Readings	Transmitter Output

F & S located to measure relative Air Flow

Flame & Furnace conditions (per each test load)

Stack Conditions (per each test load)

APPENDIX NO. 1

Boilers No. 1, No. 2 and No. 3

Primary Element Specifications Sheet

SPECIFICATION SHEET

No. 1 — FLOW PRIMARY ELEMENTS

APPENDIX C

S.O. NO.
SHEET 3 OF 3
ITEM NO 3.00
TAG NO

REVISION CODE: O - ORIGINAL DATE; B - BY BAILEY POINTE CLAIRE; C - BY CUSTOMER; D - BY BAILEY DISTRICT OFFICE; P - "AS BUILT"

DATE	CODE	DATE	CODE
Apr.13/82	P		

Bailey Meter Company Limited
205 Brunswick Boulevard, Pointe-Claire, P.Q.
H9R 1A5

ULTIMATE CUSTOMER: Moosehead Breweries Limited
PLANT: Saint John, New Brunswick.
PURCHASED BY: Moosehead Breweries Limited
APPLICATION: Steam Flow #1

P.O. NO. 599-148-19-304

SECTION 1 — GENERAL INFORMATION

1. QUANTITY	1	5. PRIMARY ELEMENT MATERIAL **	☒ 304 ☐ 316 ☐ 430 ☐ CARB. STL ☐ CH. MOLY. ☐
2. FLUID BEING MEASURED	Steam		
3. SERVICE (APPLICATION)	Steam Flow	6. PIPE ENDS (FOR BM CO. PIPE ASSY.)	☐ THREADED ☐ SQUARE END ☐ USAS BEVEL FOR ___ RING
4. PRIMARY ELEMENT TYPE ORIFICE	☒ CONC ☐ ECCEN ☐ SEGMENTAL ☐ PIPE ASSY.	7. USED WITH ITEM OR TAG NO.	1.00
4. PRIMARY ELEMENT TYPE FLOW NOZZLE	☐ FLGD ☐ WELD-IN ☐ HOLD RING ☐ PIPE ASSY.		

SECTION 2 — PIPING DATA

8. FOR ORIFICE OR FLOW NOZZLE PIPE ASSEMBLY PROCEED TO QUESTION 30		16. DIRECTION OF FLOW	☒ HORIZ ☐ UP ☐ DOWN		
		17. FLANGE TYPE	☐ SCR ☒ S-O ☐ WN ☐ LAP ☐		
9. PIPE SIZE & SCHEDULE	6" Sch. 40	18. FLANGE ANSI RATING	☐ 125 ☐ 150 ☐ 250 ☒ 300 ☐ 400 ☐ 600 ☐ 900 ☐ 1500 ☐ 2500		
10. PIPE MATERIAL	☒ CARBON STL ☐ ___ CH. MOLY. ☐ ___ STAINLESS STEEL	19. FLANGE FACING (SEE OVER)	R. F.		
11. PIPE I.D. AT INLET-INCHES	6.065	20. AGA ORIF. FLANGE UNION (300 PSI MIN. STD.)	☒ YES ☐ NO ☐ OUTLET ONL		
12. PIPE I.D. AT OUTLET-INCHES	6.065	21. K1" -INCHES	1	22. K2"-INCHES	1
13. STRAIGHT PIPE - INLET	23 Dia.	23. CONN. NIPPLE OUTLET END	THREADED ☐		SQ. END ☐
14. STRAIGHT PIPE - OUTLET	12 Dia.	24. CONN. NIPPLE INLET SIZE	K1 = 1/2"		K2 = 1/2"
15. PIPING ARRANGEMENT (SEE OVER)	Sch. 4	25. CONN. NIPPLE OUTLET SIZE	K1 = 1/2"		K2 = 1/2"
THE FOLLOWING ITEMS TO BE COMPLETED FOR HOLDING RING OR WELD-IN FLOW NOZZLES					
26. FLOW NOZZLE TYPE		28. INSTALLATION DRAWING NO.			
27. BORED PIPE DIA. AT ELEMENT OR STD. BAILEY DIMEN.		29. PIPING FABRICATOR			

SECTION 3 — FLOW DATA

30. MAXIMUM CAPACITY	30,000 pph	36. S.G. AT FLOWING TEMP/60°F △		
31. NORMAL CAPACITY	---	37. S.G. AT 60°F/60°F △		
32. FLOW UNITS	☒ LB/HR ☐ KG/HR ☐ I GPM ☐ CFH ☐ ___		FLOWING COND.	STD. COND. (GASES ONLY)
33. PRESSURE AT PRIMARY ELEMENT	100			
34. TEMPERATURE AT PRIMARY ELEMENT	Saturated	38. STEAM % MOIST. GAS % SAT.	2%	
35. VISCOSITY AT FLOWING TEMP. △		39. BAROMETER-IN. HG. OR PSIA		

SECTION 4 — MANUFACTURING DATA

40. USED WITH METER TYPE	BQ75221	48. HOLE ECCENTRICITY	
41. METER SERIAL NO.		49. HEIGHT OF SEGMENT	
42. METER DIFFERENTIAL	125" H_2O	50. NO. OF DRAIN HOLES	
43. DRILL K1 & K2 INTO TOP ☐; SIDE ☐ ; OF PIPE		51. DIA. OF DRAIN HOLES	
44. ORIFICE PLATE OR F.N. FLANGE OUTSIDE DIA.		52. LOCATE DRAIN HOLE	
45. THICKNESS OF ORIFICE PLATE OR F.N. FLANGE		53. BEVELLED OR NOT ON OUT.	
46. ORIFICE HOLE OR F.N. THROAT DIA.	4.5265	54. NO. OF CENT. PINS/SIZE	
47. RATIO HOLE OR THROAT TO PIPE DIA.	.74	55. PRIMARY ELEMENT SER. NO.	M169a3

REMARKS:

NOTE: CHANGES FROM PROPOSAL SPECS WILL BE SUBJECT TO PRICE REVIEW AND ADJUSTMENT
ITEM NOS. 28 ALSO 43 TO 55 TO BE COMPLETED BY BAILEY METER COMPANY LIMITED, POINTE CLAIRE, QUE.
* K1 IS PRESSURE CONNECTION ON INLET SIDE, K2 ON OUTLET
* 430 RECOMMENDED FOR ORIFICE PLATES FOR TEMP. OVER 500 °F (260°C)
△ NOT REQUIRED FOR STEAM AND WATER SERVICE

APPROVED BY: D. Maynard
COMPANY: Nelbal
DATE: Apr 13/82

SHEET 3 OF 3 S.O. NO.

Bailey

SPECIFICATION SHEET
No. 1 — FLOW PRIMARY ELEMENTS

SHEET 1 OF 3
ITEM NO 1.00
TAG NO

REVISION CODE: O - ORIGINAL DATE; B - BY BAILEY POINTE CLAIRE; C - BY CUSTOMER; D - BY BAILEY DISTRICT OFFICE; F - AS BUILT

DATE	CODE	DATE	CODE
Apr.13/84	O		

Bailey Meter Company Limited
205 Brunswick Boulevard, Pointe-Claire, P.Q.
H9R 1A5

ULTIMATE CUSTOMER: Moosehead Breweries Limited
PLANT: Saint John, New Brunswick
PURCHASED BY: Same
APPLICATION: S.F. From 27KPPH Cleaver Brooks #2

P.O. NO. X3038-148-100-704

SECTION 1 — GENERAL INFORMATION

1 QUANTITY	1	5. PRIMARY ELEMENT MATERIAL **	☒ 304 ☐ 316 ☐ 430 ☐ CARB. STL. ☐ CH. MOLY. ☐
2 FLUID BEING MEASURED	Steam		
3 SERVICE (APPLICATION)	S.F. from C.B. Boiler	6. PIPE ENDS (FOR BM CO. PIPE ASSY.) ☐ THREADED ☐ SQUARE END ☐ USAS BEVEL FOR ____ RING	
4 PRIMARY ELEMENT TYPE ORIFICE	☒ CONC ☐ ECCEN ☐ SEGMENTAL ☐ PIPE ASSY.		
FLOW NOZZLE	☐ FLGD ☐ WELD-IN ☐ HOLD RING ☐ PIPE ASSY	7. USED WITH ITEM OR TAG NO.	

SECTION 2 — PIPING DATA

8. FOR ORIFICE OR FLOW NOZZLE PIPE ASSEMBLY PROCEED TO QUESTION 30	-----	16. DIRECTION OF FLOW	☒ HORIZ ☐ UP ☐ DOWN
9. PIPE SIZE & SCHEDULE	6" Sch. 40	17. FLANGE TYPE	☐ SCR ☒ S-O ☐ WN ☐ LAP ☐
10. PIPE MATERIAL	☒ CARBON STL ☐ ____ CH. MOLY ☐ ____ STAINLESS STEEL	18. FLANGE ANSI RATING	☐ 125 ☐ 150 ☐ 250 ☒ 300 ☐ 400 ☐ 600 ☐ 900 ☐ 1500 ☐ 2500 ,
		19. FLANGE FACING (SEE OVER)	R.F.
11. PIPE I.D. AT INLET-INCHES	6.065	20. AGA ORIF. FLANGE UNION (300 PSI MIN. STD.)	☒ YES ☐ NO ☐ OUTLET ONLY
12. PIPE I.D. AT OUTLET-INCHES	6.065	21. K1* -INCHES / 22. K2*-INCHES	1" / 1"
13. STRAIGHT PIPE - INLET	20'	23. CONN. NIPPLE OUTLET END	THREADED ☒ SQ. END ☐
14. STRAIGHT PIPE - OUTLET	4'	24. CONN. NIPPLE INLET SIZE	K1 = 1/2 K2 =
15. PIPING ARRANGEMENT (SEE OVER)	Sch. 4	25. CONN. NIPPLE OUTLET SIZE	K1 = 1/2 K2 =
THE FOLLOWING ITEMS TO BE COMPLETED FOR HOLDING RING OR WELD-IN FLOW NOZZLES			
26. FLOW NOZZLE TYPE	------	28. INSTALLATION DRAWING NO.	
27. BORED PIPE DIA. AT ELEMENT OR STD. BAILEY DIMEN	------	29. PIPING FABRICATOR	

SECTION 3 — FLOW DATA

30. MAXIMUM CAPACITY	30,000 pph	36. S.G. AT FLOWING TEMP. 60°F △		
31. NORMAL CAPACITY	25,000 pph	37. S.G. AT 60°F/60°F △		
32. FLOW UNITS	☒ LB/HR ☐ KG/HR ☐ I GPM ☐ CFH ☐ ____		FLOWING COND.	STD. COND. (GASES ONLY)
33. PRESSURE AT PRIMARY ELEMENT	100 psig			
34. TEMPERATURE AT PRIMARY ELEMENT	Saturated	38. STEAM % MOIST. GAS % SAT.		
35. VISCOSITY AT FLOWING TEMP △		39. BAROMETER-IN. HG. OR PSIA		

SECTION 4 — MANUFACTURING DATA

40. USED WITH METER TYPE	BQ75221	48. HOLE ECCENTRICITY	
41. METER SERIAL NO.		49. HEIGHT OF SEGMENT	
42. METER DIFFERENTIAL	200" H_2O	50. NO. OF DRAIN HOLES	2
43. DRILL K1 & K2 INTO TOP ☐, SIDE ☒ OF PIPE		51. DIA. OF DRAIN HOLES	
44. ORIFICE PLATE OR F.N. FLANGE OUTSIDE DIA.		52. LOCATE DRAIN HOLE	
45. THICKNESS OF ORIFICE PLATE OR F.N. FLANGE		53. BEVELLED OR NOT ON OUT.	
46. ORIFICE HOLE OR F.N. THROAT DIA.	4.1347	54. NO. OF CENT. PINS/SIZE	
47. RATIO HOLE OR THROAT TO PIPE DIA.	.6817	55. PRIMARY ELEMENT SER. NO.	N1/6276

REMARKS:

NOTE
- CHANGES FROM PROPOSAL SPECS WILL BE SUBJECT TO PRICE REVIEW AND ADJUSTMENT
- ITEM NOS. 28 ALSO 43 TO 55 TO BE COMPLETED BY BAILEY METER COMPANY LIMITED, POINTE CLAIRE, QUE.
- K1 IS PRESSURE CONNECTION ON INLET SIDE, K2 ON OUTLET
- 430 RECOMMENDED FOR ORIFICE PLATES FOR TEMP. OVER 500 F (260 C)
- ^ NOT REQUIRED FOR STEAM AND WATER SERVICE

APPROVED BY: as per D. Skinner's tele
COMPANY: con with A. Blue
DATE: April 13/84

SPECIFICATION SHEET

No. 1 – FLOW PRIMARY ELEMENTS

SHEET
ITEM NO
TAG NO.

REVISION CODE: O – ORIGINAL DATE; B – BY BAILEY POINTE CLAIRE; C – BY CUSTOMER; D – BY BAILEY DISTRICT OFFICE; E – "AS BUILT"

DATE	CODE	DATE	CODE
Aug. 31/70	O		

Bailey Meter Company Limited
205 Brunswick Boulevard, Pointe-Claire, P.Q.

ULTIMATE CUSTOMER: Moosehead Breweries Limited
PLANT: Saint John, New Brunswick
PURCHASED BY: Foster Wheeler Limited
APPLICATION: Steam Flow Measurement # 3

P.O. NO. 1933-4

SECTION 1 – GENERAL INFORMATION

1. QUANTITY	1	5. PRIMARY ELEMENT TYPE	ORIFICE PLATE [X]; FLOW NOZ. [ ]
2. FLUID BEING MEASURED	Steam	6. TYPE OF ORIFICE PLATE	CONCENTRIC [X]; ECCENTRIC [ ]
3. SERVICE (APPLICATION)	Boiler Steam Flow		SEGMENTAL [ ]
		7. PRIMARY ELEMENT MATERIAL	MONEL [ ]; CARBON STEEL [ ]
4. USED WITH ITEM OR TAG NO.			OR Stainless Steel (3

SECTION 2 – PIPING DATA

8. ORIFICE OR FLOW NOZZLE PIPE ASSEMBLY: (IF "YES" – PROCEED TO QUESTION 30)	NO [X] YES [ ]	16. DIRECTION OF FLOW	UP [ ]; DOWN [ ]; HORIZ. [X]	
9. PIPE SIZE & SCHEDULE	6" Sch. 40	17. FLANGE TYPE	Slip – on	
10. PIPE MATERIAL	CARBON STEEL [X] OR	18. FLANGE ASA RATING	300#	
		19. FLANGE FACING (SEE OVER)	Raised Face	
		20. FLANGE TAPS	YES [ ]	NO [X]
11. PIPE I.D. AT INLET–INCHES	6.065"	21. K1*–INCHES	6"	
12. PIPE I.D. AT OUTLET–INCHES	6.065"	22. K2*–INCHES	2 3/4"	
13. STRAIGHT PIPE – INLET	9'	23. CONN. NIPPLE OUTLET END	THREADED [ ]	SQ. END [ ]
14. STRAIGHT PIPE – OUTLET	4'	24. CONN. NIPPLE INLET SIZE	K1 = 1/2"	K2 = 1/2"
15. PIPING ARRANGEMENT (SEE OVER)		25. CONN. NIPPLE OUTLET SIZE	K1 = 1/2"	K2 = 1/2"
THE FOLLOWING ITEMS TO BE COMPLETED FOR HOLDING RING OR WELD-IN FLOW NOZZLES				
26. FLOW NOZZLE TYPE		28. *INSTALLATION DRAWING NO.*		
27. BORED PIPE DIA. AT ELEMENT OR STD. BAILEY DIMEN.		29. PIPING FABRICATOR		

SECTION 3 – FLOW DATA

30. MAXIMUM CAPACITY	30,000 #/hr.	36 [illegible]	Spec. Vol. 3.595	
31. NORMAL CAPACITY		37. S.G. AT 60°F / 60°F		
32. UNITS OF MEASUREMENT	#/hr.		FLOWING COND.	STD. COND. (GASES ONLY)
33. PRESSURE AT PRIMARY ELEMENT	110 psig.			
34. TEMPERATURE AT PRIMARY ELEMENT	Sat.	38. STEAM % MOIST. GAS % SAT.	Dry	
35. VISCOSITY AT FLOWING TEMP.		39. BAROMETER-IN. HG. OR PSIA		

SECTION 4 – MANUFACTURING DATA

40. USED WITH METER TYPE	DC3653X	48. *HOLE ECCENTRICITY*	
41. METER SERIAL NO.	701578	49. *HEIGHT OF SEGMENT*	
42. METER DIFFERENTIAL	120" H_2O	50. *NO. OF DRAIN HOLES*	2
43. *DRILL K1 & K2 INTO TOP* [ ]; *SIDE* [X] *OF PIPE*		51. *DIA. OF DRAIN HOLES*	3/32"
44. *ORIFICE PLATE OR F.N. FLANGE OUTSIDE DIA.*	9 7/8"	52. *LOCATE DRAIN HOLE*	Top & Bottom
45. *THICKNESS OF ORIFICE PLATE OR F.N. FLANGE*	1/16"	53. *BEVELLED OR NOT ON OUT.*	Bevelled
46. *ORIFICE HOLE OR F.N. THROAT DIA.*	4.465	54. *NO. OF CENT. PINS/SIZE*	
47. *RATIO HOLE OR THROAT TO PIPE DIA.*	.737	55. *PRIMARY ELEMENT SER. NO.*	M-11811

REMARKS:

*K1 IS PRESSURE CONNECTION ON INLET SIDE; K2 ON OUTLET SIDE. ITEMS IN ITALICS TO BE COMPLETED BY BAILEY METER COMPANY LIMITED, POINTE CLAIRE, QUE. *REFER TO SPECIFICATIONS IN QUOTATION: CHANGES FROM QUOTATION MAY REQUIRE PRICE ADJUSTMENT*

mo
tor
fr
hal
ham /ng.

APPROVED BY:
COMPANY:
DATE:

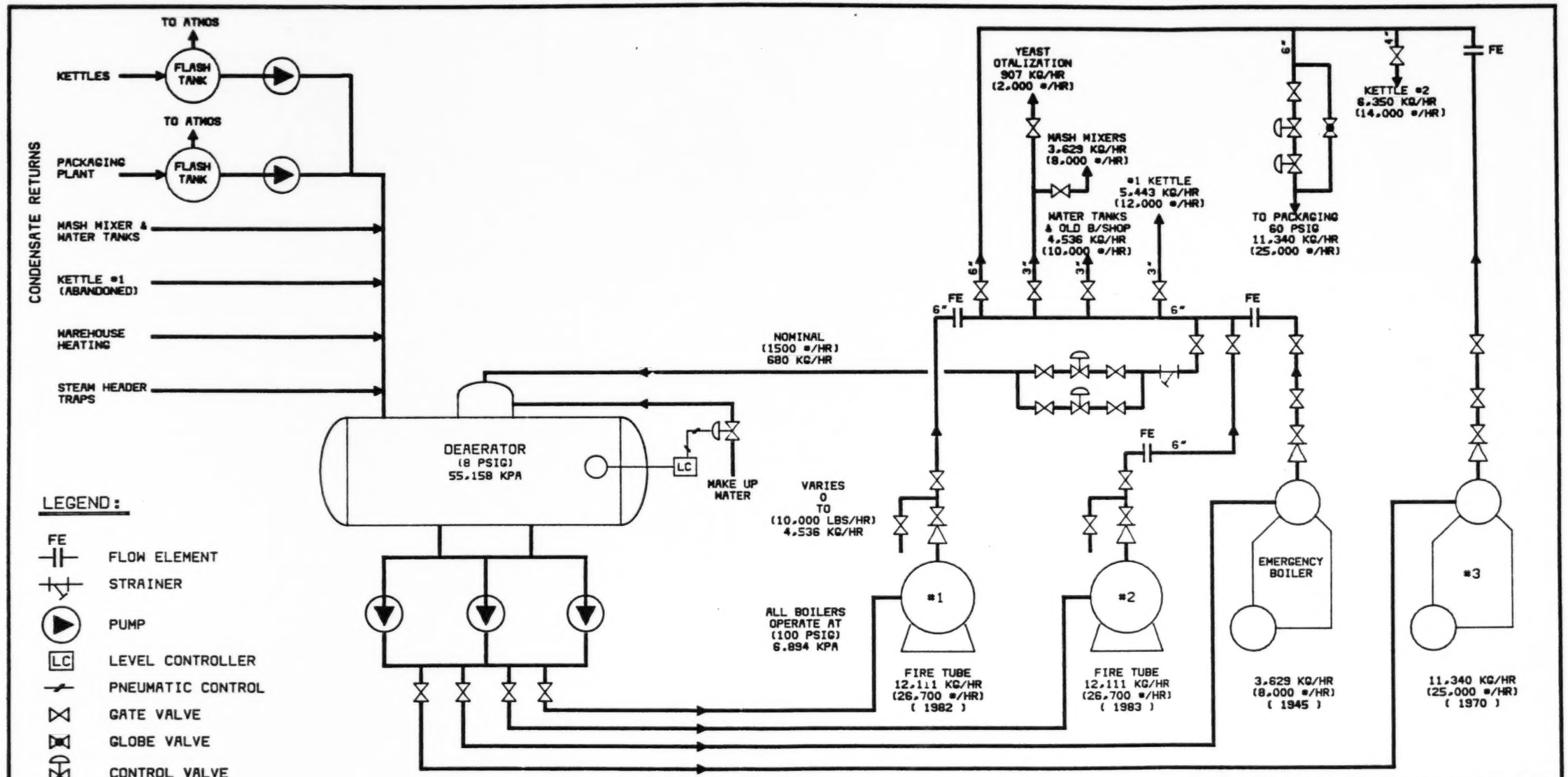
FORM LEDI-168 (FRONT)

SHEET ____ OF ____ : S.O. NO. ____

APPENDIX NO. 2

Drawings

	Title	Number
(1)	Steam and Condensate Simplified Schematic	B-401
(2)	Theoretical Versus Actual Steam Load	B-402
(3)	Simplified Process Flow Diagram	B-403


TO ATMOS
KETTLES
FLASH TANK
TO ATMOS
PACKAGING PLANT
FLASH TANK
CONDENSATE RETURNS
MASH MIXER & WATER TANKS
KETTLE #1 (ABANDONED)
WAREHOUSE HEATING
STEAM HEADER TRAPS
DEAERATOR (8 PSIG) 55.158 KPA
LC
MAKE UP WATER
NOMINAL (1500 #/HR) 680 KG/HR
VARIES 0 TO (10,000 LBS/HR) 4,536 KG/HR
ALL BOILERS OPERATE AT (100 PSIG) 6.894 KPA
YEAST OTALIZATION 907 KG/HR (2,000 #/HR)
MASH MIXERS 3,629 KG/HR (8,000 #/HR)
#1 KETTLE 5,443 KG/HR (12,000 #/HR)
WATER TANKS & OLD B/SHOP 4,536 KG/HR (10,000 #/HR)
TO PACKAGING 60 PSIG 11,340 KG/HR (25,000 #/HR)
KETTLE #2 6,350 KG/HR (14,000 #/HR)
FE
6"
3"
#1
#2
#3
EMERGENCY BOILER
FIRE TUBE 12,111 KG/HR (26,700 #/HR) (1982)
FIRE TUBE 12,111 KG/HR (26,700 #/HR) (1983)
3,629 KG/HR (8,000 #/HR) (1945)
11,340 KG/HR (25,000 #/HR) (1970)

LEGEND:

- FE — FLOW ELEMENT
- STRAINER
- PUMP
- LC — LEVEL CONTROLLER
- PNEUMATIC CONTROL
- GATE VALVE
- GLOBE VALVE
- CONTROL VALVE
- CHECK VALVE

REV.	ISSUED TO	ISSUED FOR	NO.	DATE	BY	REVISIONS	CKD.
0	CLIENT	REVIEW					

DESIGNED EDS	DRAWN TAT
CHECKED DESIGN EDS / DFTG. TAT	DATE DEC 11/85
	SCALE NTS
APPROVED RCN	SPEC. —
PROJ. ENG. RCN	A3063B

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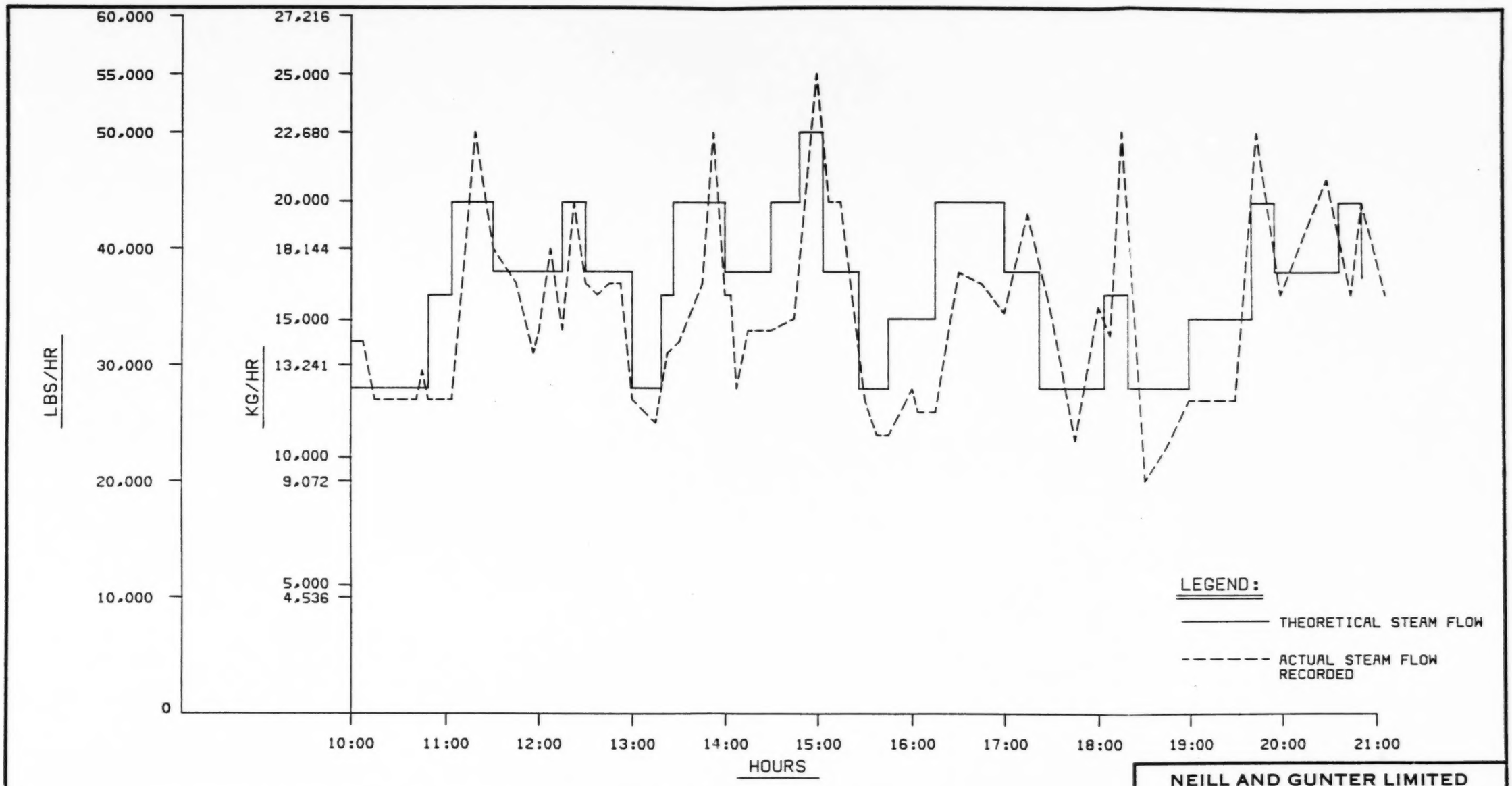
ENERSOLVE DEMONSTRATION PROJECT

MOOSEHEAD BREWERIES LIMITED

STEAM AND CONDENSATE SIMPLIFIED SCHEMATIC

JOB NO.	DWG. NO.	REV.
11836	B-401	0



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0	CLIENT	REVIEW					

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	SCALE NTS
APPROVED RCN	SPEC. —
PROJ. ENG. RCN	A3064B

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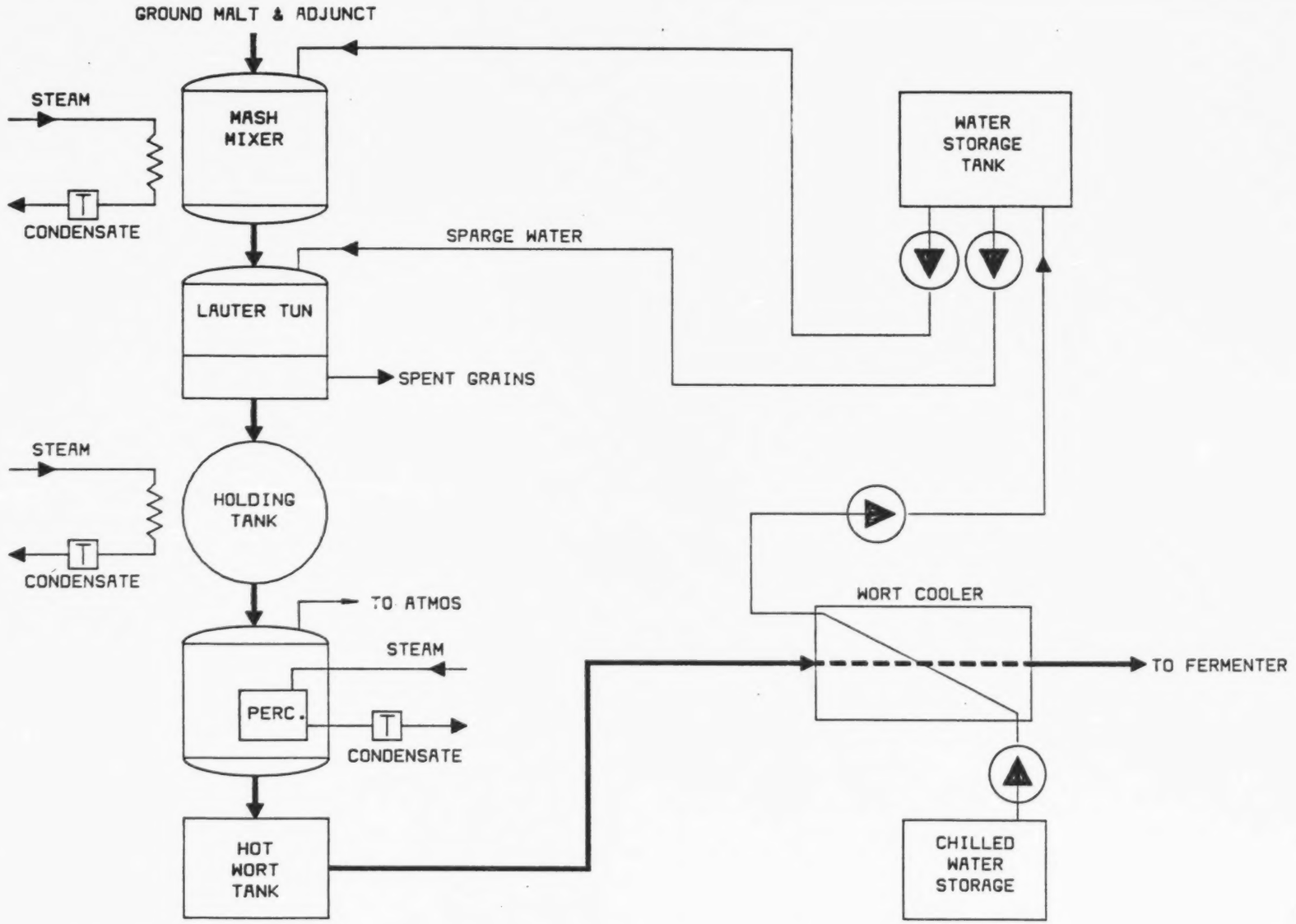
THEORETICAL VERSES ACTUAL STEAM LOAD
TYPICAL OPERATING DAY 13 FEB 85

JOB NO.	DWG. NO.	REV.
11836	B-402	0



REV.	ISSUED TO	ISSUED FOR	NO.	DATE	BY	REVISIONS	CKD.
0	CLIENT	REVIEW					

DESIGNED RCN	DRAWN TAT
CHECKED DESIGN RCN / DFTG. TAT	DATE DEC 30/85
	SCALE NTS
APPROVED RCN	SPEC.
PROJ. ENG. RCN	A3077A

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ENERSOLVE DEMONSTRATION PROJECT

MOOSEHEAD BREWERIES LIMITED

SIMPLIFIED
PROCESS FLOW DIAGRAM

JOB NO. 11836 | DWG. NO. B-403 | REV. 0